Engineering Analysis

Sklar Exploration
Castleberry Oil & Gas Field, Area No. 1
SEC. 5, 6, 7, 8, & 17 T4N, R13E, Conecuh County, AL
Facility No. 103-0021

FACILITY HISTORY

There are currently a large number of Oil and Gas production wells located in southeast Conecuh County that are a part of the Little Cedar Creek Field, as named by the State of Alabama Oil & Gas Board. The wells comprising the Little Cedar Creek Field are currently permitted to both Sklar Exploration (Sklar) and Pruet Production Company (Pruet).

When permitting these wells the Department has subdivided the field into “Areas”, considering the proximity of each well to other wells under the same ownership/operatorship to do so. Enough well “Areas” in the Little Cedar Creek Field have been permitted that the Department has divided the Little Cedar Creek Field itself for permit naming purposes, designating Sklar’s well Areas as “Castleberry” and the wells now operated by Pruet, then by Midroc Operating Company, to be in “Cedar Creek”. This is important because Pruet’s Cedar Creek, Area Nos. 4 & 5 slightly overlap with Sklar’s Castleberry Oil and Gas Field, Area No. 1.

Sklar was first issued the Title V Major Source Operating Permit for the Castleberry Oil & Gas Field, Area No. 1 wells on January 1, 2009.

PROJECT SUMMARY

On June 26, 2013, Sklar applied for the Title V permit for Area No. 1 to be renewed; on January 27, 2014, Sklar requested that the renewal application be withdrawn and submitted an application for a Synthetic Minor Operating Permit (SMOP) in its stead.

Sklar states that production from the wells in Area No. 1 has been much lower than anticipated in the last six months, reporting an average of 60 Mcf/day of gas. Sklar reasons that the expected maximum emissions for a year at that production rate would be well under 100 tons/yr for each criteria pollutant.

This application covers nine wells. Two other wellsites within Area No. 1, wells 8-7 and 8-15, are dry and abandoned. This permit application does not request any new or modified emission sources.

PROCESS DESCRIPTIONS

There are two related processes for each well which will be covered by Synthetic Minor Operating Permit No. 103-0021.

PROCESS NO. 1—OIL & GAS EXTRACTION

This process will primarily be used. The full well stream (consisting of oil, water, and associated gas) flows from a well into a high pressure separator. After the separator, the stream passes through a heater treater which primarily separates oil and water. The gas goes to the flare or to the nearby gas plant located in Pruet's Cedar Creek, Area No. 1 (Facility No. 103-0011). The liquids flow into the storage tanks until sale or custody transfer. A closed vent system (CVS) is used to capture stock tank vapors and send the vapors to the onsite well flare, and a vapor recovery unit (VRU) may draw from that cvs and send the vapor to the gas plant. An electric power oil pump motor is used to pump oil from the power oil tank back into the ground in order to facilitate the extraction process.

PROCESS NO. 2—OIL EXTRACTION

In the event that the gas plant is offline or the well is not connected to the gas plant via a pipeline, these wells may be used to produce oil. This process is similar to the oil and gas extraction process except that the gas is continuously flared.

Each well is equipped with one (1) heater treater, one (1) high pressure separator, one (1) emergency flare, one (1) salt water storage tank, and two (2) crude oil storage tanks. Each well is also permitted for one (1) power oil storage tank.

EMISSIONS

The original Title V for Castleberry Field Area No. 1 calculated potential emissions for the wells (fourteen at that time) using an estimated 2 MMscf/day of gas, or 5.952 Mscf/hr per well. Table 1 below shows those estimated potential emissions, adjusted for nine wells. Production data is taken from the January 1, 2009 Title V MSOP application for facility 103-0021 and its associated Statement of Basis, and gas quality data is up-to-date from the SMOP application.

	Pollutant	Heaters	Flare	Total Emissions
Criteria Pollutant Emissions (TPY)	PM2.5/10	0.147	-	0.147
	SO2	0.006	0.103	0.109
	NOX	1.932	23.235	25.167
	CO	1.623	126.424	128.047
	VOC	0.106	138.631	138.738
	Total HAPs	-	-	0.000
GHG Emissions (mTPY)	CO2	2307.063	43,774.008	46,081.070
	N2O	0.004	0.053	0.058
	CH4	0.043	121.020	121.064
	Mass Sum	2307.110	43,895.081	46,202.192
	CO2e	2309.445	46,815.373	49,124.819

Table 1: Potential Emissions for Permitted Sources in Ton/yr

The expected emissions are based on potentially flaring 0.060 MMcf/day of gas per well, which is in turn an estimate provided by Sklar in the SMOP application and originates with recent recorded production data. The expected emissions from permitted sources, except the tanks, at the facility are given in Table 2 below. The storage tanks' vapors are captured and routed to the flare.

	Pollutant	Heaters	Flare	Total Emissions
Criteria Pollutant Emissions (TPY)	$PM_{2.5/10}$	0.147	-	0.147
	SO_2	0.006	0.043	0.049
	NO_X	1.932	9.759	11.691
	CO	1.623	53.098	54.721
	VOC	0.106	58.225	58.331
	Total HAPs	-	-	0.000
GHG Emissions (mTPY)	CO_2	2,307.063	18,385.083	20,692.146
	N_2O	0.004	0.022	0.027
	CH_4	0.043	50.829	50.872
	Mass Sum	2,307.110	18,435.934	20,743.045
	CO_{2e}	2,309.445	19,662.457	21,971.902

Table 2: Expected Emissions for Permitted Sources in Ton/yr

REGULATIONS

There are several regulations that could apply to the wellsite equipment:

1. ***ADEM Administrative Code Rule 335-3-4-.01(1)(a),*** *"Visible Emissions,"* states that no person shall emit to the atmosphere an opacity of greater than twenty percent (20%) over a six (6) minute period. ***ADEM 335-3-4-.01(b)*** states that during one six minute period in any sixty minute period a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity.

   a. Because the fuel for the heater treaters would be primarily natural gas, no opacity is expected from these units.
   b. The flares would require opacity monitoring, which would consist of daily visual inspections. In the event that opacity is observed, immediate corrective action should be taken.
   c. Method 9 or Method 22 should be used to determine visible emissions.

2. ***ADEM Administrative Code*** Rule 335-3-4-.03 covers particulate emissions from fuel burning equipment. Since the heater treaters would be classified as a new source, they must meet the Class I county maximum allowable emissions of 0.5 lb/MMBTU. However, the combustion of natural gas results in very low particulate emissions. Thus, the emissions from the heater treaters should never approach the limit and no monitoring will be required for this regulation.

3. ***ADEM Administrative Code*** Rule 335-3-5-.01(b) covers fuel combustion sulfur limitations for Category II counties, which includes Conecuh Co. Therefore, the heater treaters may not emit more than 4.0 lb/MMBTU of sulfur compounds. Since the heater treaters would burn sweet natural gas [natural gas with no appreciable H_2S], there would be negligible expected SO_2 emissions. Therefore, no monitoring will be required for SO_2 for the heater treaters other than measuring and recording the produced gas sulfur content. The sulfur content of the well gas should be determined from a sample analyzed while utilizing the Tutwiler procedures in 40 CFR §60.648 or the chromatographic analysis procedures in ASTM E-260 or the stain tube procedures in GPA 2377-86 or those provided by the stain tube manufacture..

4. ***ADEM Administrative Code*** Rule 335-3-5-.03(1-2) covers sulfur emissions for petroleum production. Hydrogen sulfide (H_2S) may not be emitted in a greater quantity than 0.10 grain per standard cubic foot (scf), or 160 ppmv, unless it is properly burned to maintain a ground concentration of less than 20 ppb beyond property limits, as averaged over a 30 minute period. Currently, most of the wells in this area have an appreciable concentration of H_2S in the produced wellstream. These streams are currently subject to this regulation. Compliance with this regulation would be achieved by burning the gas in the flare, or sending the gas to a processing plant, both of which are being done.

5. ***ADEM Administrative Code*** Rule 335-3-6-.03 applies to the loading and storage of volatile organic compounds (VOCs). Per Rule 335-3-6-.03(4), this regulation does not apply to crude petroleum produced, separated, treated, or stored in the field. Since the tanks each store crude petroleum at the production source in the field, this regulation does not apply.

6. ***ADEM Administrative Code*** Rule 335-3-6-.04 applies to fixed roof petroleum liquid storage tanks. Per Rule 335-3-6-.03(3)(b), this regulation does not apply to storage tanks with a capacity less than 423,000 gallons, and used to store crude petroleum oil prior to custody transfer. Since the tanks each store crude oil prior to custody transfer, this regulation does not apply.

7. ***ADEM Administrative Code*** Rule 335-3-10-.02(9)(b), refers to Subpart Kb of NSPS, and applies to VOC tanks constructed after July 23, 1984. §60.110b(d)(4) states that vessels with a design storage capacity of less than, or equal to, 1590 m^3 (420,000 gallons) used for petroleum or condensate stored, treated, or processed prior to custody transfer are exempt from this regulation. Each of the tanks at each site has a volume of less than 420,000 gallons, and stores condensate prior to custody transfer. Therefore, the tanks are exempt from this regulation.

8. ***ADEM Administrative Code*** Rule 335-3-11-.06(33) refers to NESHAPS Subpart HH. This regulation applies to Oil and Gas Production Facilities that is: 1. a major or area source of hazardous air pollutants (HAPs) and either 2. produces, upgrades, or stores liquid hydrocarbons prior to custody transfer or 3. produces, upgrades, or stores natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is

delivered to the final end user (§63.760 (a)(1),(2) & (3)). The following definitions from §63.761 will be used:

a. A Major Source in §63.2 is defined as a site in which the potential to emit is greater than, or equal to, 10 Ton/yr for a single HAP or greater than, or equal to, 25 Ton/yr for all HAPs. HAPs emissions at an oil and gas production or exploration site may not be aggregated for any associated equipment other than glycol dehydrators and storage vessels with the potential for flash emissions.

b. Associated equipment means all equipment from the wellhead to the point of custody transfer except glycol dehydrators and storage vessels with the potential for flash emissions.

c. An Area Source is defined as any non-Major Source.

Because the potential to emit HAPs for the facility is less than what is defined above, the facility is not a major source as defined in §63.761. Additionally, Area Source requirements apply solely to sites equipped with tri-ethylene glycol dehydrators. Since no wells have a glycol dehydrator, the facility is not an affected area source. Thus, no applicable requirements of 40 CFR 63, Subpart HH apply to this facility.

9. ***ADEM Administrative Code*** Rule 335-3-14-.04 refers to the Prevention of Significant Deterioration (PSD) regulation. On January 18, 2011, the Department adopted Greenhouse Gas regulations [GHG] as part of this regulation. No review would be necessary since this permit covers no new sources. Nevertheless, the potential emissions of the wells combined are under the PSD limits for both criteria pollutants and GHG, so PSD regulations would not apply.

10. ***Air Toxics Program,*** the permit application did not indicate that a significant amount of Air Toxics would be emitted from the proposed units, nor does the Department expect any Air Toxics emissions of significant quantities to be emitted. Therefore, no Air Toxics Review will be performed for this project.

11. ***New Source Performance Standards (NSPS)*** Subpart OOOO was promulgated by EPA on April 17, 2012, and contains SO_2 and VOC requirements for natural gas production wells and natural gas processing plants constructed, reconstructed, or modified after August 23, 2011. The facilities in Area No. 1 were all constructed before 2009 and have not been reconstructed or modified, and the wells have not been hydraulicly refractured; therefore, Subpart OOOO does not apply.

12. ***Title V Regulations:*** In order to avoid having a Title V permit and obtain a Synthetic Minor Operating Source Permit, Sklar has requested a 95 Ton/yr limit on NO_X, CO, VOC, and SO_2 emissions.

Monitoring for well gas properties must be undertaken and would consist of taking a representative sample at least once each three-month period from each well. To demonstrate that the 95 TPY limit is not exceeded, any gas sent to flare shall be tested for its H_2S content using the Tutwiler procedures in 40 CFR §60.648 or the chromatographic analysis procedures in ASTM E-260 or the stain tube procedures in GPA 2377-86 or those provided by the stain tube manufacture. The VOC content, the molecular weight, and the BTU content of the gas should be determined using the chromatographic analysis procedures in 40 CFR Part 60 Appendix A, Method 18, Method 25A, or equivalent methods and procedures. If a well produces no gas, as demonstrated by both the continuous sales meter and the continuous flared gas meter, then no sample would be required. If gas production returns, then an immediate sample would be required.

RECOMMENDATIONS

This analysis indicates that these sources would meet the requirements of all federal and state rules and regulations. Therefore, I recommend that Sklar Exploration Company be issued Synthetic Minor Operating Permit No. 103-0021-X001, upon receipt of permitting fees and completion of a 15 day public notice period.

______________________________ May 23, 2014
R. Jackson Rogers, Jr. Date
Industrial Minerals Section
Energy Branch
Air Division

ATTACHMENT A:

CALCULATIONS

PART A – WELL EMISSION CALCULATIONS

	Pollutant	Heaters	Flare	Total Emissions
Criteria Pollutant Emissions (TPY)	PM2.5/10	0.147	-	0.147
	SO2	0.006	0.103	0.109
	NOX	1.932	23.235	25.167
	CO	1.623	126.424	128.047
	VOC	0.106	138.631	138.738
	Total HAPs	-	-	0.000
GHG Emissions (mTPY)	CO2	2307.063	43,774.008	46,081.070
	N2O	0.004	0.053	0.058
	CH4	0.043	121.020	121.064
	Mass Sum	2307.110	43,895.081	46,202.192
	CO2e	2309.445	46,815.373	49,124.819

Table 1: Potential Emissions for Permitted Sources in Ton/yr

	Pollutant	Heaters	Flare	Total Emissions
Criteria Pollutant Emissions (TPY)	$PM_{2.5/10}$	0.147	-	0.147
	SO_2	0.006	0.043	0.049
	NO_X	1.932	9.759	11.691
	CO	1.623	53.098	54.721
	VOC	0.106	58.225	58.331
	Total HAPs	-	-	0.000
GHG Emissions (mTPY)	CO_2	2307.063	18,385.083	20,692.146
	N_2O	0.004	0.022	0.027
	CH_4	0.043	50.829	50.872
	Mass Sum	2307.110	18,435.934	20,743.045
	CO_{2e}	2309.445	19,662.457	21,971.902

Table 2: Expected Emissions for Permitted Sources in Tons/yr

Calculations derived from the following spreadsheets:

Potential Flare Emissions

Data				
Volume	53,571.4	scf/hr	469.286	MMscf/yr
H_2S mol%	0.00026	mol%	1285.71	Mscf/day
OP Hours	8760	Hrs	142.86 per well	
Heat Content	1456.2	Btu/scf		
Heat Input	78.01	MMBtu/hr[1]	0.01	lb/hr H_2S Feedrate to flare [3]
VOC MW	11.19	lb/lb-mol[2]		
Destruction Eff	0.98	(Assuming flare 98% efficient)		
CO_2	0.264	mol%	44.01	(Lb/Lb-mol)
CH_4	60.906	mol%	16.043	(Lb/Lb-mol)

AP 42 Emissions Factors		
NO_X=	0.068	lb/MMBtu
CO=	0.37	lb/MMBtu

40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)		
N_2O=	0.0001	kg/MMBtu

GWP*		*Revised 11/29/2013
N_2O=	298	
CO_2=	1	
CH_4=	25	

Allowable Flare Emission Calculations

Pollutants								=	
SO_2	1.689 Lb SO_2[4] / MScf	53.57 MScf / Hr	0.000 Mol%	8,760 Hr / Year	1 Ton / 2,000 Lb			=	**0.103 Tons / Year**
NO_x	0.068 lb / MMBtu	78.01 MMBtu / Hr	8,760 Hr / Year	1 Ton / 2,000 Lb				=	**23.235 Tons / Year**
CO	0.37 lb / MMBtu	78.01 MMBtu / Hr	8,760 Hr / Year	1 Ton / 2,000 Lb				=	**126.424 Tons / Year**
VOC[5]	53,571 Scf / Hr	1 Lb-Mole / 378.9 Scf	11.19 Lb VOC / Lb-Mole	8,760 Hr / Year	1 Ton / 2,000 Lb	0.02		=	**138.631 Tons / Year**
CO_2[5,6] Combusted	0.98	469,285,714 Scf / Yr	1.63622	1 Lb-Mole / 378.9 Scf	44.01 Lb CO_2 / Lb-mole	1 Ton / 2,000 Lb		=	**43,702.06 Tons / Year**
CO_2 Uncombusted	469,285,714 Scf / Yr	0.264 / 100	1 Lb-Mole / 378.9 Scf	44.01 Lb CO_2 / Lb-mole	1 Ton / 2,000 Lb			=	**71.95 Tons / Year**
N_2O	0.001 Metric ton / kg	0.001028 MMBtu / Scf	53,571 Scf / Hr	0.0001 kg / MMBtu	8,760 Hr / Year	1.103 Tons / 1 Metric Ton		=	**0.0532 Tons / Year**
CH_4 Uncombusted	469,285,714 Scf / Yr	0.02	60.906 / 100	1 Lb-Mole / 378.9 Scf	16.043 Lb CH_4 / Lb-mole	1 Ton / 2,000 Lb		=	**121.02 Tons / Year**
Mass Sum	43,774.01 Tons / Year	+	0.0532 Tons / Year	+	121.02 Tons / Year			=	**43,895.08 Tons / Year**
CO_2e	43,774.01 TPY X 1	43,774.01 CO_2	+	0.0532 TPY X 298	15.86 N_2O	+	121.02 TPY X 25 / 3,025.51 CH_4	=	**46,815.37 Tons / Year**

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded

H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/378.9) *(H_2S mol%/100) * (34 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 1.689 Lb SO_2/MScf of Gas

= (1,000 Scf/MScf) * (1%/100)*(1Lb-Mole/378.9 Scf)* (64 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:

$\Sigma Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of

Calculated using 5.952 Mscf/(hr·well)

EXPECTED FLARE EMISSIONS

Data

Volume	22,500.0	scf/hr	197.1	MMscf/yr	**AP 42 Emissions Factors**		
H_2S mol%	0.00026	mol%	540	Mscf/day	NO_x=	0.068	lb/MMBtu
OP Hours	8760	Hrs	60 per well		CO=	0.37	lb/MMBtu
Heat Content	1456.2	Btu/scf					
Heat Input	32.76	MMBtu/hr[1]	0.01	lb/hr H_2S Feedrate to flare [3]			
VOC MW	11.19	lb/lb-mol[2]					
Destruction Eff	0.98	(Assuming flare 98% efficient)					
CO_2	0.264	mol%	44.01	(Lb/Lb-mol)			
CH_4	60.906	mol%	16.043	(Lb/Lb-mol)			

40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)		
N_20=	0.0001	kg/MMBtu

GWP*		*Revised 11/29/2013
N_20=	298	
CO_2=	1	
CH_4=	25	

Potential Flare Emission Calculations

Pollutants									
SO_2	1.689 Lb SO_2 [4] / MScf	22.50 MScf / Hr	0.000 Mol%	8,760 Hr / Year	1 Ton / 2,000 Lb			=	**0.043 Tons / Year**
NO_x	0.068 lb / MMBtu	32.76 MMBtu / Hr	8,760 Hr / Year	1 Ton / 2,000 Lb				=	**9.759 Tons / Year**
CO	0.37 lb / MMBtu	32.76 MMBtu / Hr	8,760 Hr / Year	1 Ton / 2,000 Lb				=	**53.098 Tons / Year**
VOC[5]	22,500 Scf / Hr	1 Lb-Mole / 378.9 Scf	11.19 Lb VOC / Lb-Mole	8,760 Hr / Year	1 Ton / 2,000 Lb	0.02		=	**58.225 Tons / Year**
CO_2 [5,6] Combusted	0.98	197,100,000 Scf / Yr	1.63622	1 Lb-Mole / 378.9 Scf	44.01 Lb CO_2 / Lb-mole	1 Ton / 2,000 Lb		=	**18,354.86 Tons / Year**
CO_2 Uncombusted	197,100,000 Scf / Yr	0.264 / 100	1 Lb-Mole / 378.9 Scf	44.01 Lb CO_2 / Lb-mole	1 Ton / 2,000 Lb			=	**30.22 Tons / Year**
N_2O	0.001 Metric ton / kg	0.001028 MMBtu / Scf	22,500 Scf / Hr	0.0001 kg / MMBtu	8,760 Hr / Year	1.103 Tons / 1 Metric Ton		=	**0.0223 Tons / Year**
CH_4 Uncombusted	197,100,000 Scf / Yr	0.02	60.906 / 100	1 Lb-Mole / 378.9 Scf	16.043 Lb CH_4 / Lb-mole	1 Ton / 2,000 Lb		=	**50.83 Tons / Year**
Mass Sum	18,385.08 Tons / Year	+	0.0223 Tons / Year	+	50.83 Tons / Year			=	**18,435.93 Tons / Year**
CO_2e	18,385.08 TPY X 1	18,385.08 CO_2	+	0.0223 TPY X 298	6.66 N_2O	+	50.83 TPY X 25 / 1,270.71 CH_4	=	**19,662.46 Tons / Year**

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded

H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/378.9) *(H_2S mol%/100) * (34 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 1.689 Lb SO_2/MScf of Gas

= (1,000 Scf/MScf) * (1%/100)*(1Lb-Mole/378.9 Scf)* (64 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:
$\Sigma\, Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of carbon atoms in gas hydrocarbon constituent j: 1 for methane and carbon dioxide, 2 for ethane, 3 for propane, etc.

Calculated using 540 Mscf/day or 60 Mscf/(day·well)

POTENTIAL HEATER EMISSIONS

Data:			
H_2S mol%	0.00026	mol%	
Op Hours	8760	Hrs	
Heat Content	1,456	Btu/scf	Produced NG
Flowrate	0.343	MScf/Hr	
Heat Input	500,000	Btu/hr	
Fuel HHV Correction Factor	1.428		

Based on NG with Btu/Content of 1020

AP-42 EF (NG)		
PM=	7.6	Lb/MMScf
NO_X=	100	Lb/MMScf
CO=	84	Lb/MMScf
VOC=	5.5	Lb/MMScf

GWP*	
N_2O=	298
CO_2=	1
CH_4=	25

*Revised 11/29/2013

(Table C-1 & C-2) 40 CFR Part 98 Sub C GHG Emission Factors for NG		
N_20=	0.0001	kg/MMBtu
CO_2=	53.06	kg/MMBtu
CH_4=	0.001	kg/MMBtu

Heater Emission Calculations

Pollutants							wells		
PM	7.6 Lb / MMScf	0.500 MMBtu / Hr	Scf / 1,456 Btu	8,760 *Hr* / *Year*	1 Ton / 2,000 Lb	1.428	9	=	**0.147 Tons / Year**
SO_2	*1.689 Lb SO_2* / *MScf*	0.343 MScf / Hr	0.00026 Mol%	8,760 *Hr* / *Year*	1 Ton / 2,000 Lb		9	=	**0.006 Tons / Year**
NO_X	100 Lb / MMScf	0.500 MMBtu / Hr	Scf / 1,456 Btu	8,760 *Hr* / *Year*	1 Ton / 2,000 Lb	1.428	9	=	**1.932 Tons / Year**
CO	84 Lb / MMScf	0.500 MMBtu / Hr	Scf / 1,456 Btu	8,760 *Hr* / *Year*	1 Ton / 2,000 Lb	1.428	9	=	**1.623 Tons / Year**
VOC	5.5 Lb / MMScf	0.500 MMBtu / Hr	Scf / 1,456 Btu	8,760 *Hr* / *Year*	1 Ton / 2,000 Lb	1.428	9	=	**0.106 Tons / Year**
CO_2	0.5 MMBtu / Hr	53.06 kg / MMBtu	*0.001 Metric Ton* / *kg*	*8,760 Hr* / *Year*	*1.103 Tons* / *1 Metric Ton*		9	=	**2,307.06 Tons / Year**
N_2O	0.5 MMBtu / Hr	0.0001 kg / MMBtu	*0.001 Metric Ton* / *kg*	*8,760 Hr* / *Year*	*1.103 Tons* / *1 Metric Ton*		9	=	**0.00435 Tons / Year**
CH_4	0.5 MMBtu / Hr	0.001 kg / MMBtu	*0.001 Metric Ton* / *kg*	*8,760 Hr* / *Year*	*1.103 Tons* / *1 Metric Ton*		9	=	**0.04348 Tons / Year**

Mass Sum	2,307.06 Tons / Year (CO_2)	+	0.0043 Tons / Year (N_2O)	+	0.0435 Tons / Year (CH_4)	=	**2,307.11 Tons / Year**
CO_2e	2,307.06 TPY X 1 = 2,307.06 (CO_2)	+	0.0043 TPY X 298 = 1.30 (N_2O)	+	0.0435 TPY X 25 = 1.09 (CH_4)	=	**2,309.45 Tons / Year**

ATTACHMENT B:

DRAFT PERMIT PROVISOS

ADEM
Alabama Department of Environmental Management

SYNTHETIC MINOR OPERATING PERMIT

PERMITTEE: SKLAR EXPLORATION

FACILITY NAME: CASTLEBERRY OIL & GAS FIELD, AREA NO. 1

LOCATION: SEC. 5, 6, 7, 8, & 17 T4N, R13E, CONECUH COUNTY, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
101-0021-X001	Castleberry Field, Area No. 1 9 operating wells, each with: One (1) 0.5 MMBtu/hr Heater Treater Two (2) - 16,800 gal Crude Storage Tanks One (1) - 16,800 gal Saltwater Storage Tanks One (1) - 21,000 gal Power Oil Storage Tanks One (1) Closed Vent System & Process Flare

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code §§22-22A-1 to 22-22A-15 (2006 Rplc. Vol. and 2007 Cum. Supp.), and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: May 23, 2014

Alabama Department of Environmental Management

Page 1 of 9

DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE

CCL&T 5-5 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0505-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0505-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0505-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0505-04)
- Closed vent system & flare (F-0505-01)

Craft Ralls 5-8 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0508-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0508-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0508-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0508-04)
- Closed vent system & flare (F-0508-01)

Craft Ralls 5-10 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0510-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0510-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0510-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0510-04)
- Closed vent system & flare (F-0510-01)

Craft Ralls 5-14 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0514-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0514-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0514-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0514-04)
- Closed vent system & flare (F-0514-01)

Craft Mack 7-2 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0702-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0702-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0702-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0702-04)
- Closed vent system & flare (F-0702-01)

Craft Mack 8-2 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0802-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0802-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0802-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0802-04)
- Closed vent system & flare (F-00802-01)

Craft Brye 8-4 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0804-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0804-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0804-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0804-04)
- Closed vent system & flare (F-0804-01)

Craft Ralls 8-12 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-0812-01)
- Two (2) – 16,800 Gallon crude storage tank (T-0812-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-0812-03)
- One (1) – 21,000 Gallon power oil storage tank (T-0812-04)
- Closed vent system & flare (F-0812-01)

Craft Mack 17-4 oil & gas production & separation site
- One (1) - 0.5 MMBtu/Hr heater treater (HT-1704-01)
- Two (2) – 16,800 Gallon crude storage tank (T-1704-01 & 02)
- One (1) – 16,800 Gallon salt water storage tank (T-1704-03)
- One (1) – 21,000 Gallon power oil storage tank (T-1704-04)
- Closed vent system & flare (F-1704-01)

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. In case of shutdown of air pollution control equipment for scheduled maintenance for a period greater than **8 hours,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

5. In the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants, the person responsible for such equipment shall notify the Air Division within an additional 24 hours and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

6. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

7. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

8. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

9. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

10. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

11. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

12. Castleberry Oil & Gas Field, Area No. 1 shall comply with the following emission standards:

    (a) The total SO_2, NO_X, CO, and VOC emissions from the facility shall not exceed **95 Tons per Twelve (12) Consecutive Months for each pollutant**.

    (b) The facility shall not discharge into the atmosphere from any source of emission, particulate of an opacity greater than twenty percent (20%) opacity over a six (6) minute averaging, except for under the following condition:

        (1) During one six (6) minute period in any sixty (60) minute period, a person may discharge into the atmosphere from any source of emission, particulate of an opacity not greater than that designated as forty percent (40%) opacity.

    (c) The facility shall not cause or permit the emission of a process gas stream containing more than 0.10 grain of hydrogen sulfide (H_2S) per standard cubic foot (scf) into the atmosphere unless it is properly burned to maintain the ground level concentrations of H_2S to less twenty (20) parts per billion (ppb) beyond plant property limits, averaged over a thirty minute period, except for under the following condition:

        (1) Venting to the atmosphere of any process gas stream subject to proviso 12(c) shall be allowed for a period not to exceed fifteen (15) consecutive minutes during which vessels and equipment are being de-pressured an/or emptied and the reduced pressure will not allow flow of the gas to the flare.

13. To demonstrate compliance with proviso 12 (a) the following requirements shall be met:

    (a) The heater treater shall burn one of the following fuels:

        (1) Natural gas, OR

        (2) Propane, OR

        (3) Other fuel approved by the Department

    (b) A monthly record of the information specified in provisos 13(b) (1) through (4) of this permit shall be maintained and made available for inspection.

        (1) Facility-wide SO_2, NO_X, CO, and VOC emissions shall be calculated for each pollutant in accordance to the requirements specified in proviso 13(b)(1)(i) through (iii) of this permit.

            (i) Emissions (Tons/Month) ≈

            Total Flare Emission (Tons /Month)

(ii) Emission (Tons/Twelve Consecutive Months) =
∑ of previous 11 month's emissions (Tons/Month) + current month's emissions (Tons/Month)

(iii) Monthly emissions from the flare shall be those calculated in proviso 13(b)(2) of this permit.

(2) Flare emissions shall be calculated in accordance with provisos 13(b)(2)(i) through (ix):

(i) Volume of gas burned in flare =
[Stream Volume Burned (MScf/Month)]

(ii) Stream (MMBtu/Month) =
[Stream Volume Burned MScf/Month)]
X [SG Stream (Btu/Scf]
X [1 MMScf/1000 MScf]

(iii) Stream H_2S (Lbs/Month) =
[Stream Volume Burned (MScf/Month)]
X [1000 Scf/MScf]
X [1 Mole/380 Scf)]
X [{SG Stream (H_2S Mole%)}/{100}]
X [34 Lbs. H_2S/Mole H_2S]

(iv) Flare H_2S (Lbs/Month) =
∑ of Stream H_2S (Lbs/Month)

(v) Number of hours that the flare was operated during the month =
[Flare (Hours/Month)]

(vi) Flare H_2S feed (Lbs/Hour) =

$$\frac{\text{Flare } H_2S \text{ (Lbs/Month)}}{\text{Flare (Hours/Month)}}$$

(vii) Flare (MMBtu/Month) =
∑ of Stream (MMBtu/Month)

(viii) Total Flare Emissions (Tons/Month) =

$$\frac{\sum \text{Flare Emissions (Lbs/Month)}}{[\text{ 2000 Lbs/Ton }]}$$

(3) A record of the date, starting time, and duration of each period when a permit requirement was not met along with the cause(s) and corrective action(s).

(4) A record of daily visual inspections conducted on the flare.

14. To demonstrate compliance with proviso 12 (b) the following requirements shall be met:

(a) Opacity monitoring shall be conducted on the flare as specified in either proviso 14(a)(1) OR 14(a)(2):

(1) Provided process gas other than pilot gas is being sent to the flare, a daily visual inspection of the flare shall be performed to determine the presence or absence of visible emissions as follows:

(i) Each daily visual inspection shall be conducted in accordance to the requirements specified in 40 CFR Part 60 Appendix A Method 9 OR 40 CFR Part 60 Appendix A Method 22 OR by other methods and procedures approved by the Department.

(ii) Each daily visual inspection shall be conducted during daylight hours and shall consist of a visual survey of the flare flame area to identify if there are any visible emissions, other than condensed water vapor, being emitted from the flare.

(iii) A record of the time, date, and results of each visual inspection of the flare shall be maintained.

(iv) Each daily visual inspection shall be conducted for a period of at least 6 minutes.

(v) Provided visible emissions in excess of the opacity standards are observed at any time during the visual inspection, a visual emissions observation as specified in 14(b) shall be conducted.

(vi) A daily visual inspection is not required during periods that the production facility is unmanned by plant personnel or when a process stream is not being sent to the flares.

(2) Provided process gas is being sent to the gas plant in Cedar Creek Area No. 1 instead of to the flare, a weekly visual inspection of the flare for visible emissions shall be performed adhering to the same standards as provisos 14(a)(1)(i)-(v).

(b) Provided that plant personnel observes visible emissions from the flare in excess of opacity standards at any time and a process gas stream other than the pilot gas is being sent to the flare, a visible emission observation as specified in provisos 14(c)(1) through (5) shall be performed.

(1) 40 CFR Part 60 Appendix A, Method 22, Method 9, or other methods and procedures approved by the Department shall be utilized to perform the visible emission observations.

(i) Visible emission observations utilizing Method 9 shall be conducted by an observer that is certified and familiar with Method 9 methods and procedures.

(ii) Visible emissions that are observed utilizing Method 22 shall be deemed to have a reading in excess of 20% opacity and visible emission shall not be observed for more than one 6-minute period within a 60-minute observation period.

(iii) Visible emission observations shall be conducted during daylight hours.

(2) The duration of each observation shall be no less than fifteen consecutive minutes.

(3) Provided visible emission are observed in excess of the opacity standards, immediate corrective measures shall be undertaken to eliminate the visible emissions.

(4) A record of the time, date, duration, and immediate corrective actions taken to eliminate visible emissions shall be maintained.

(5) Record of visible emission observation time, date, and duration shall be maintained.

15. To demonstrate compliance with proviso 12(c) the following requirements shall be met:

(a) Each process gas stream that has to be vented to the atmosphere shall be captured and sent through a closed vent system to the flare to be burned.

(b) The facility shall conduct a process flow design evaluation of each gas-liquid separation site in conjunction with visual inspections of each.

(c) The flare shall be operated with a flame or spark present at the flare tip at all times that a process gas stream could be vented to it. Compliance shall be demonstrated by the following:

(1) Installing and operating a continuous monitoring system (i.e. thermocouple or other equivalent device) capable of detecting the presence of a pilot flame.

(i) Calibration, maintenance and operation of the monitoring system shall be performed in accordance with manufacturer's specifications.

OR

(2) Performing a daily visual inspection of the flare tip for the presence or absence of a spark or flame.

(i) Visual inspections shall be made from a location that provides the best view of the flare tip and/or flare pilot flame or flare igniter.

(ii) Record of inspection must be maintain.

(d) When possible and practicable, a continuous metering system shall be utilized that is capable of continuously monitoring and recording the flow rate of each sour gas stream that is to be vented to the flare prior to entry into the flare.

(1) The continuous measurement may be made with a single meter through which all of the sour gas steams flow, or with multiple meters through which an individual sour gas stream or multiple sour gas streams flow.

(i) Calibration, maintenance and operation of metering system shall be performed in accordance to manufacturer's specification.

(2) Volumetric flow of sour gas streams that are not continuously measured shall be accounted for by utilizing special estimating methods (i.e. engineer estimates, material balance, computer simulation, special testing, etc).

(e) Each stream that may be burned in the flare shall adhere to the following requirements:

(1) The hydrogen sulfide (H_2S) content of each process stream that can be sent to the flare shall be determined in accordance to the requirements specified in proviso 15(e)(1)(i) and (ii) of this permit.

(i) Testing shall consist of capturing one representative sample of the stream at a frequency of no less than once quarterly.

(ii) The sample collected shall be analyzed while utilizing the Tutwiler procedures in 40 CFR §60.648 or the chromatographic analysis procedures in ASTM E-260 or the stain tube procedures in GPA 2377-86 or those provided by the stain tube manufacture.

[SG Stream (H_2S Mole %)]

(2) The volatile organic compound (VOC) content, Btu content, and molecular weight of each process stream that can be sent to the flare shall be determined in accordance to the requirements specified in proviso 15(e)(2)(i) and (ii) of this permit.

(i) Provided the flare is located at a gas-liquid separation site, testing shall consist of capturing one representative sample of the stream at a frequency of no less than once quarterly.

(ii) The sample collected shall be analyzed while utilizing the chromatographic analysis procedures in 40 CFR Part 60 Appendix A, Method 18, Method 25A, or equivalent methods and procedures.

[SG Stream (VOC Mole%)]
[SG Stream (Mole Wt)]
[SG Stream (BTU/Scf)]

(3) Provided multiple process streams can be sent to the flare and it is possible to capture a common stream whose contents would be representative of all the streams, that common stream may be used instead of the individual process streams.

(4) The frequency of testing may be modified upon receipt of Department approval.

(f) The maximum H_2S federate to each flare shall not exceed 500 lb/hr.

16. Periodic Monitoring Reports meeting the following requirements shall be submitted to the Department:

(a) Report contents shall be:

(1) A summary of the monthly records kept per proviso 13(b),

OR

(2) As otherwise requested by the Department.

(b) Reporting frequency shall be:

(1) Semi-annual, or as otherwise approved by the Department.

(2) Reports shall cover a calendar semi-annual period and shall be submitted to the Department on the following reporting schedule:

Reporting Period	Submittal Date
January 1st through June 30th	*July 31st*
July 1st through December 31st	*January 31st*

17. All records, unless otherwise specified, shall be maintained in a permanent form suitable for inspection and shall be retained for at least two (2) years following the date of each occurrence, including the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment.

18. All deviations from the permit requirements shall be reported to the Department within 48 hours of the deviation(s) or by the next work day. The notification shall included a statement with regards to the date, time, duration, cause and corrective actions taken to bring the source(s) back into compliance.

May 23, 2014
DATE